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July 1, 2005

BY OVERNIGHT DELIVERY AND E-FILE

Mary L. Cottrell, Secretary
Department of Telecommunications and Energy
One South Station
Boston, MA 02110

Re: Bay State Gas Company, D.T.E. 05-27

Dear Ms. Cottrell:

Enclosed for filing, on behalf of Bay State Gas Company ("Bay State"), please find Bay State's responses to the following information requests:

From the Attorney General:

AG-9-55	AG-13-2	AG-19-27	AG-22-13	AG-22-14
AG-22-33	AG-22-46	AG-23-5 (Supp)	AG-24-2	AG-24-3
AG-24-4	AG-24-5	AG-24-6	AG-24-7	AG-24-8
AG-24-9	AG-24-10	AG-24-11	AG-24-12	AG-24-13
AG-24-14	AG-24-15	AG-24-16	AG-24-17	AG-24-18
AG-24-19	AG-24-20	AG-24-21	AG-24-22	AG-27-1
AG-27-2	AG-27-3	AG-27-4	AG-27-5	AG-27-6
AG-27-8				

From the Department:

DTE-4-14	DTE-4-16	DTE-4-25	DTE-4-29	DTE-4-42
DTE-4-43	DTE-4-49	DTE-4-50	DTE-4-52	DTE-5-26

DTE-7-11	DTE-7-12	DTE-7-13	DTE-7-14	DTE-7-15
DTE-7-16	DTE-7-17	DTE-7-18	DTE-15-19	DTE-19-15
DTE-19-16	DTE-19-17	DTE-19-18	DTE-19-19	DTE-19-20
DTE-19-21	DTE-19-24	DTE-20-6	DTE-22-1	DTE-22-2
DTE-22-3	DTE-22-4	DTE-22-5	DTE-22-6	DTE-22-7
DTE-22-8	DTE-22-9	DTE-22-10	DTE-22-11	

From DOER:

DOER-1-2	DOER-1-3	DOER-1-4	DOER-1-5	DOER-1-6
DOER-1-10	DOER-1-17			

From MOC:

MOC-1-1	MOC-1-3	MOC-1-4	MOC-3-9	MOC-4-1
MOC-4-6				

From the UWUA Local 273:

UWUA-1-3	UWUA-1-11 (BULK)		UWUA-1-14	UWUA-1-34
UWUA-2-3	UWUA-2-5	UWUA-2-6	UWUA-2-8	UWUA-2-16
UWUA-2-25	UWUA-2-40	UWUA-2-41	UWUA-3-1	UWUA-3-2
UWUA-3-3	UWUA-3-5			

From the USWA:

USWA-1-9	USWA-1-10	USWA-2-1	USWA-2-3	USWA-2-5
USWA-2-8	USWA-2-9	USWA-2-12	USWA-2-14	USWA-2-22

Please do not hesitate to telephone me with any questions whatsoever.

Very truly yours,

Patricia M. French

cc: Per Ground Rules Memorandum issued June 13, 2005:

Paul E. Osborne, Assistant Director – Rates and Rev. Requirements Div. (1 copy)
A. John Sullivan, Rates and Rev. Requirements Div. (4 copies)
Andreas Thanos, Assistant Director, Gas Division (1 copy)
Alexander Cochis, Assistant Attorney General (4 copies)
Service List (1 electronic copy)

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
NINTH SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL
D. T. E. 05-27

Date: June 30, 2005

Responsible: Stephen H. Bryant, President

AG-9-55 Has the Company, or any affiliate for the Company's benefit, considered outsourcing any of the functions performed by Company employees during the 2004 test year? Explain in complete detail the Company's outsourcing plans and quantify the expected savings to the Company by account. Include in this response all cost / benefit analyses of the outsourcing plans, any reports or memorandums discussing outsourcing, and any RFPs issued for outsourcing and the responses to these RFPs. Identify by company name, address, phone number and principal contact any firms that the Company will use, or is considering, for outsourcing.

Response: Please see the Company's response to DTE-18-01.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
THIRTEENTH SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL
D. T. E. 05-27

Date: June 30, 2005

Responsible: Lawrence R. Kaufmann, Consultant (PBR)

AG-13-2 Please provide complete copies of the testimony and exhibits regarding Mr. Kaufmann's testimony in *Boston Gas Company*, D.T.E. 03-40, referred to on page 9 of his prefiled testimony in this case. Please also provide a complete copy of the productivity and input price trends studies along with all workpapers used in that case, along with all workpapers, calculations, formulas, assumptions, and supporting documentation.

Response: Please see the response to AG-13-1, as well as Attachment AG-13-2(a) and Attachment AG-13-2(b).

Exhibit KEDNE/LRK-2

X-Factor Calibration for Boston Gas

Pacific Economics Group
Economic and Litigation Consulting

X-Factor Calibration for Boston Gas

January 28, 2003

Larry Kaufmann, Ph.D.
Partner

David Hovde, M.S.
Senior Economist

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TABLE OF CONTENTS

1. INTRODUCTION AND SUMMARY

1.1 Introduction

Boston Gas (BoGas) proposes to update the performance based regulation (PBR) plan that applies to its gas distribution services. Under the plan, escalation in the company's average price would be limited by a price cap index ("PCI"). PCI growth would be determined by a formula that includes an inflation measure, an X-factor, and a Z-factor. The design of the PCI would incorporate industry trends in input prices and productivity.

Pacific Economics Group, LLC ("PEG") is the nation's leading provider of energy industry productivity studies. Our personnel have testified many times on productivity research. BoGas has retained PEG to calibrate the X-factor of its proposed price cap index.

This report presents the results of our productivity research. Following a brief summary of the study, Section 2 addresses the role of productivity research in index-based regulation. Key details of our productivity work for BoGas are presented in Section 3. Further details are provided in the Appendix.

1.2 Summary of Research

1.2.1 Total Factor Productivity

A total factor productivity ("TFP") index is the ratio of an output quantity index to an input quantity index. It is used to measure the efficiency with which firms convert production inputs to outputs. The TFP index developed for this study measured the TFP growth trend of the Northeast U.S. gas distribution industry. The growth trend of a TFP trend index is the difference between the trends in output and input quantity indexes. Our output quantity index included trends in the number of customers served and volumes delivered by gas distributors. Our input quantity index summarized trends in the amounts of different inputs that distributors use.

1.2.2 Role of Indexing in Regulation

Indexing plans are a common form of PBR worldwide. They can be based on a solid foundation of economic principle and empirical research. According to index logic, the price trend of an industry that, in the long run, earns a competitive return is equal to its unit cost trend. It is therefore sensible to calibrate a PCI for gas distributors to track the unit cost rend of the gas distribution industry. Index logic also shows that an industry's unit cost trend can be expressed as the difference between its input price and TFP trends.

The appropriate calibration of a PCI depends on the selected inflation measure. BoGas proposes to use the GDPPI as the inflation measure in its PCI. In this case, X-factor should be calibrated to track the difference between TFP trends for the industry and the U.S. economy.

1.2.3 Indexing Research

We calculated the TFP trend of Northeast gas distributors as providers of gas distribution services. Gas distribution was defined to include all gas delivery and customer account and customer information services that distributors provide. Established methods and respected, publicly available data were employed in index development. The sample period was 1990-2000. The year 2000 is the latest for which productivity indexes for the US economy are as yet available. Measures of economy-wide productivity trends are needed to compute the productivity differential.

The industry TFP growth was 0.53% per annum. By way of comparison, the federal government's multifactor productivity index for the U.S. private business sector grew at a an average annual rate of 0.98% over the same period. The differential between the TFP trends for Northeast gas distributors and the U.S. economy is therefore -0.45%.

PEG also calculated trends in input price indexes for gas distributors and the U.S. economy. If there are significant differences between these trends and the PCI uses an economy-wide inflation measure, it may be appropriate to include an inflation differential in the X-factor. The inflation differential would be equal to input price inflation for the economy minus input price inflation for the industry.

PEG's research shows that input prices for Northeast gas distributors grew at an average rate of 3.02% per annum over the 1990-2000 period. The input price trend for the U.S. economy was 3.10% over the same period. The inflation differential is therefore 0.1%.

2. TFP Indexes and Performance-Based Regulation

2.1 TFP Indexes

A TFP index is the ratio of an output quantity index to an input quantity index.

$$TFP = \frac{Output\ Quantities}{Input\ Quantities}. \qquad [1]$$

It is used to compare the efficiency with which firms convert inputs to outputs. Comparisons can be made between firms at a point in time or for the same firm (or group of firms) at different points in time. The indexes we developed for this study measure TFP trends in the gas distribution industry.

The growth trend in a TFP trend index is the difference between the trends in the component output and input quantity indexes.

$$trend\ TFP = trend\ Output\ Quantities - trend\ Input\ Quantities. \qquad [2]$$

The output quantity index of an industry summarizes trends in the workload that it performs. The input quantity index of an industry summarizes trends in the amounts of production inputs used. TFP grows when the output quantity index rises more rapidly (or falls less rapidly) than the input quantity index. TFP can rise or fall in a given year but typically trends upward over time.

2.2 Role of Indexing Research in Regulation

The logic of economic indexes is useful in calibrating in BoGas's proposed PCI. Our analysis starts with the principle that the trend in the revenue of an industry that earns, in the long run, a competitive rate of return equals the trend in its costs.

$$trend\ Revenue^{Industry} = trend\ Cost^{Industry} \qquad [3]$$

Suppose, now, that we subtract from both sides of [3] the trend in a measure of the quantity of outputs that the industry provides. Now

$$trend\,Revenue^{Industry} - trend\,Output^{Industry} = trend\,Cost^{Industry} - trend\,Output^{Industry} \qquad [4]$$

Pacific Economics Group
Economic and Litigation Consulting

This is equivalent to saying that the trend in the industry's revenue per unit of output equals the trend in its unit cost.

$$trend\ (Revenue/Output)^{Industry} = trend\ (Cost/Output)^{Industry} = trend\ Unit\ Cost.^{Industry} \qquad [5]$$

The long run character of the principle represented in [3] merits emphasis. Fluctuations in input prices, demand, and other external business conditions will cause earnings to fluctuate absent adjustments in production capacity. Since capacity adjustments are costly, however, they will typically not be made rapidly enough to prevent short-term fluctuations in the rates of return around the competitive norm. The long run is a period long enough for the competitive industry to adjust capacity to more secular trends in market conditions.

This discussion implies that PCIs calibrated to track the industry unit cost trend are consistent with how prices evolve n competitive markets. This is sometimes known as the "competitive market paradigm" for PCI design. In addition, it can be shown that the trend in an industry's *total* cost is the sum of the industry's input price and input quantity trends. It follows that the trend in an industry's unit cost is the difference between the trends in its input prices index and its TFP index.[2]

$$trend\,Unit\,Cost^{Industry} = trend\,Input\,Prices^{Industry} - trend\,TFP^{Industry} \qquad [6]$$

A PCI is calibrated to track the industry unit cost rend if it satisfies the above formula.

Appropriate calibration of formula [6] can depend on the proposed inflation measure. Suppose, for example, that the GDPPI is used as the inflation measure. The GDPPI measures inflation in the prices of *final* goods and services in the U.S. economy.

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[2] Here is the full logic behind this result:

$$\begin{aligned} trend\,Unit\,Cost^{Industry} &= trend\,Cost^{Industry} - trend\,Customers^{Industry} \\ &= \left(trend\,Input\,Prices^{Industry} + trend\,Input\,Quantities^{Industry}\right) \\ &\quad - trend\,Output\,Quantities^{Industry} \\ &= trend\,Input\,Prices^{Industry} \\ &\quad - \left(trend\,Customers^{Industry} - trend\,Input\,Quantities^{Industry}\right) \\ &= trend\,Input\,Prices^{Industry} - trend\,TFP^{Industry} \end{aligned}$$

The same indexing logic detailed above suggests that input price inflation of the economy exceeds GDPPI inflation by the economy's TFP growth.

$$trend\ Input\ Prices^{economy} = trend\ GDPPI + trend\ \ TFP^{economy} \qquad [7]$$

A PCI that uses the GDPPI as an inflation measure and tracks the industry unit cost trend then satisfies the following formula.

$$\begin{aligned} trend\ PCI &= trend\ Input Price^{industry} - trend\ \ TFP^{industry} \\ &= trend GDPPI + trend TFP^{economy} - trend TFP^{industry} \\ &\ + \left[trend\ Input Price^{industry} - \left(trend\ GDPPI + trend\ TFP^{economy}\right)\right] \qquad [8] \\ &= trend GDPPI - \begin{bmatrix} \left(trend\ TFP^{industry} - trend TFP^{econcomy}\right) \\ + \left(trend\ Input Price^{economy} - trend\ Input\ Price^{industry}\right) \end{bmatrix} \\ &= trend GDPPI - X \end{aligned}$$

It can be seen that the X-factor is the sum of two terms. One is the productivity differential i.e., the difference between the TFP trends of the industry and the economy. X is larger (slowing price growth) as the productivity differential increases. The second term is the inflation differential. This is equal to the difference between the input price growth trends of the economy and the industry. X is larger (slowing price growth) as this differential increases.

BoGas proposes to use the GDPPI as an inflation measure in its PCI. It is therefore sensible to calibrate its X-factor using the TFP and inflation differentials between the gas distribution industry and the U.S. economy.

3. SUMMARY OF INDEXING RESEARCH

This section presents an overview of our work to calculate the TFP trend of gas distributors in the northeastern U.S. The discussion is largely non-technical. Additional and more technical details of the research are provided in the Appendix which follows.

3.1 Data

The primary source of data used in our gas delivery productivity research has changed over time. For earlier years of the sample period, the primary source was the *Uniform Statistical Report* (USR). Gas utilities are asked to file these reports annually with the American Gas Association (AGA). USR data for some variables are aggregated and published annually by the AGA in *Gas Facts.*

USRs are unavailable for most sampled distributors for the later years of the sample period. Some distributors no longer file USRs. Some that do file USRs do not release them to the public. The development of a satisfactory sample therefore requires that PEG obtain basic cost and quantity data from alternative sources including, most notably, reports to state regulators. Fortunately, these reports are fairly standardized since they often use as templates the Form 2 report that interstate gas pipelines are asked to file with the Federal Energy Regulatory Commission. Other sources of data used in our work primarily pertain to input prices. They include DRI/McGraw Hill; Whitman, Requardt & Associates; the Bureau of Economic Analysis ("BEA") of the U.S. Department of Labor.

Our TFP trend calculations are based on high quality data for 16 Northeastern gas distributors. The Massachusetts Department of Telecommunications and Energy (DTE) accepted a regional definition of the gas distribution industry in the last PBR plan for Boston Gas.[3] This study maintained a focus on regional TFP growth.

[3] The DTE based this decision on evidence that costs differed between Northeast gas distributors and distributors in the rest of the nation. As discussed in our companion report, *The Cost Performance of Boston Gas*, PEG's most recent research also finds that there are significantly different costs between Northeast and other U.S. gas distributors.

The sample distributors grouped by region are listed in Table 1. The sample includes most of the region's larger distributors. The table also indicates that the sampled LDCs served about 61% of all gas end users in the Northeast.

3.2 Indexing Details

3.2.1 Scope

Cost figures play an important role in our productivity trend research. The applicable total cost of gas distribution was calculated as gas distribution operation and maintenance ("O&M") expenses plus the cost of gas plant ownership and a share of any common costs. Gas distribution O&M expenses are defined as the total O&M expenses of the distributor less any expenses incurred for natural gas production or procurement. The operations corresponding to this definition of cost include all O&M costs associated with gas delivery to end users, customer account, and information and other customer services of LDCs.

In constructing the input quantity index, we decomposed cost into three major input categories: capital services, labor services, and other O&M inputs. The cost of gas delivery labor was defined as the sum of O&M salaries and wages and pensions and other employee benefits. The cost of other O&M inputs was defined to be O&M expenses net of these labor costs and of gas production and procurement expenses. This category includes the services of contract workers, insurance, real estate rents, equipment leases, and miscellaneous materials.

This study used a service price approach to capital cost measurement. Under this approach, the cost of capital is the product of a capital quantity index and the price of capital services. This method has a solid basis in economic theory and is well established in the scholarly literature.

Table 1

NORTHEAST SAMPLE FOR THE INDUSTRY TFP TREND RESEARCH

Company	Number of Customers (2000)
Boston Gas	542,792
Brooklyn Union Gas	1,191,679
Central Hudson Gas & Electric	63,851
Commonwealth Gas	243,853
Connecticut Energy	164,012
Connecticut Natural Gas	155,641
Consolidated Edison	1,048,357
New Jersey Natural Gas	414,620
Niagara Mohawk	544,075
Orange & Rockland Utilities	118,718
PECO	430,842
People's Natural Gas	353,715
PG Energy	155,992
Providence Energy	172,965
Public Service Electric & Gas	1,621,128
Rochester Gas & Electric	285,944
Sample Total	**7,508,184**
Percentage of Northeast Total	**60.87%**

3.2.2 TFP

The growth rate in each TFP index was the difference between the growth rates in industry output and input quantity indexes. Growth in the output quantity index was a weighted average of growth in the number of customers and gas delivery volumes. Weights were based on the cost elasticities for each output from our econometric research

The growth rate in each input quantity index was a weighted average of the growth rates in quantity subindexes for capital, labor, and other O&M inputs. The weights were based on the shares of these input classes in the industry's total gas distribution cost.

3.2.3 Sample Period

The sample period should be long enough to reflect the industry's long-run TFP trend. A period of 10 years is often deemed to be sufficient to fulfill this goal in regulatory proceedings. Since the most recently available data on the productivity of the US economy are for 2000, and US productivity trends are needed to compute the productivity differential, the sample period chosen for our research was 1990-2000.

3.3 Index Results

3.3.1 TFP

Table 2 and Figure 1 report the 1990-2000 average annual growth rates in the gas delivery TFP and component output and input quantity indexes for Northeast gas distributors. Analogous results are presented for the growth trend of the TFP index for the private business sector U.S. economy

It can be seen that the TFP trend for the gas distribution industry was 0.53% per annum. Output quantity growth averaging an annual 1.42% outpaced input quantity growth averaging 0.89% annually. A 0.98% growth trend was calculated for the multifactor productivity index for the U.S. private business sector over the same period. The TFP differential was therefore -0.45% over the 1990-2000 period.

Table 2

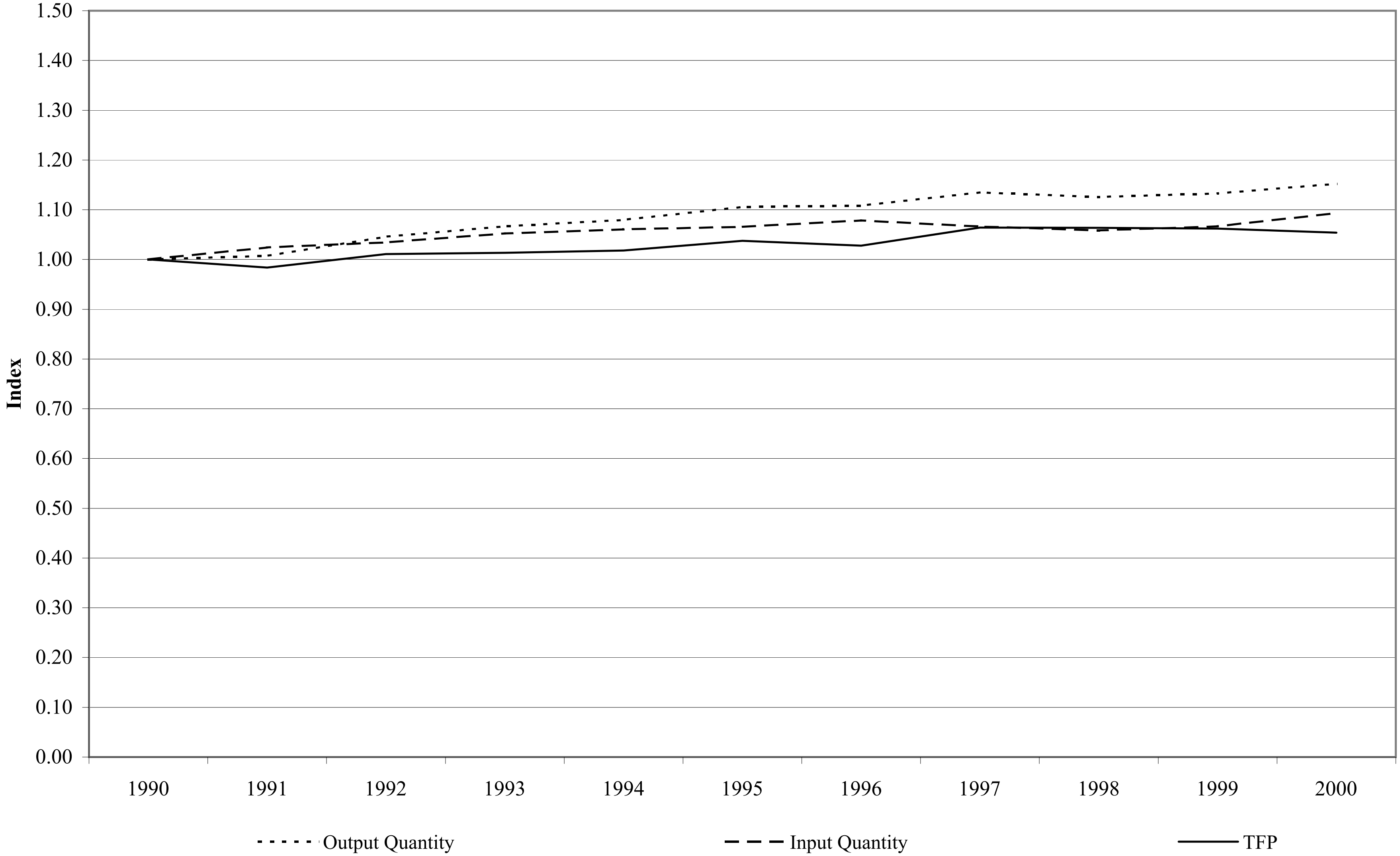
TFP Results:
Northeast Gas Distributors

	Output Quantity Index (A)	Input Quantity Index (B)	TFP Index (C=A/B)	U.S. Private Business Sector*	TFP Differential
1990	1.000	1.000	1.000	95.5	
1991	1.007	1.024	0.984	94.5	
1992	1.046	1.035	1.011	96.7	
1993	1.067	1.052	1.014	97.1	
1994	1.080	1.060	1.018	98.2	
1995	1.106	1.066	1.038	98.4	
1996	1.108	1.078	1.028	100.0	
1997	1.135	1.066	1.064	101.2	
1998	1.126	1.058	1.064	102.5	
1999	1.133	1.067	1.062	103.4	
2000	1.152	1.093	1.054	105.3	
Average Annual Growth Rate 1990-2000	1.42%	0.89%	0.53%	0.98%	-0.45%

* Source: U.S. Bureau of Labor Statistics

Figure 1

TFP Results: Northeast Gas Distributors



3.3.2 Input Prices

Tables 3 and 4 report the 1990-2000 growth trends in input prices for the gas distribution industry and the U.S. economy. In table 3, it is seen that industry input prices grew by 3.02% per annum over the 1990-2000 period.

Table 4 compares this to the input price trend for the U.S. economy. As previously discussed, indexing logic implies that the U.S. input price trend can be computed as the sum of GDPPI growth plus the U.S. MFP trend. It can be seen that, over the 1990-2000 period, this calculation yields an input price trend of 3.10% per annum for the U.S. economy. The difference between the industry and economy-wide input price trends is therefore 0.1%.

Table 3

INPUT PRICE INDEXES FOR THE NORTHEAST U.S. GAS DISTRIBUTION INDUSTRY

	Input Price Index		Labor Price		Capital Price		Non-Labor O&M Price	
	Index	% Change	Index	% Change	Index	% Change	GDP-PI	% Change
1990	1.00		1.00		14.38		86.53	
1991	1.04	4.1%	1.04	3.8%	15.01	4.3%	89.66	3.6%
1992	1.14	9.1%	1.08	3.8%	17.13	13.2%	91.85	2.4%
1993	1.21	5.7%	1.13	4.5%	18.38	7.0%	94.05	2.4%
1994	1.26	4.3%	1.19	4.9%	19.22	4.5%	96.01	2.1%
1995	1.27	0.6%	1.21	1.6%	19.14	-0.4%	98.10	2.2%
1996	1.30	2.6%	1.23	2.2%	19.68	2.8%	100.00	1.9%
1997	1.38	5.7%	1.25	1.7%	21.29	7.9%	101.95	1.9%
1998	1.38	0.1%	1.29	2.6%	21.07	-1.0%	103.20	1.2%
1999	1.41	2.0%	1.29	0.0%	21.60	2.5%	104.66	1.4%
2000	1.35	-4.0%	1.31	1.8%	20.07	-7.4%	107.04	2.2%
Average Annual Growth Rate 1990-2000		3.02%		2.72%		3.33%		2.13%

Table 4

INPUT PRICE INDEXES FOR THE NORTHEAST GAS DISTRIBUTION INDUSTRY AND THE U.S. ECONOMY

	GDP-PI		MFP (Private Business)		Input Price Index: U.S. Economy		Input Price Index: Gas Distribution Industry		
	Index	% Change[1] [A]	Index	% Change[1] [B]	Index	% Change[1] [C]=[A]+[B]	Index	% Change[1] [D]	Difference[2] [C]-[D]
1990	86.5		95.5		1.043		1.000		
1991	89.7	3.6%	94.5	-1.1%	1.070	2.50%	1.041	4.1%	-1.6%
1992	91.9	2.4%	96.7	2.3%	1.122	4.71%	1.141	9.1%	-4.4%
1993	94.1	2.4%	97.1	0.4%	1.153	2.78%	1.208	5.7%	-3.0%
1994	96.0	2.1%	98.2	1.1%	1.191	3.19%	1.261	4.3%	-1.1%
1995	98.1	2.2%	98.4	0.2%	1.219	2.36%	1.269	0.6%	1.7%
1996	100.0	1.9%	100.0	1.6%	1.263	3.53%	1.303	2.6%	0.9%
1997	102.0	1.9%	101.2	1.2%	1.303	3.12%	1.380	5.7%	-2.6%
1998	103.2	1.2%	102.5	1.3%	1.336	2.50%	1.380	0.1%	2.4%
1999	104.7	1.4%	103.4	0.9%	1.367	2.28%	1.408	2.0%	0.3%
2000	107.0	2.2%	105.3	1.8%	1.423	4.07%	1.353	-4.0%	8.1%
Average Annual Growth Rate 1990-2000		2.13%		0.98%		3.10%		3.02%	0.08%

[1] All computed growth rates are logarithimic.

[2] Statistical tests revealed that the difference of 0.08% is *not* significantly different from 0%.

APPENDIX

This appendix contains additional details of our X-factor calibration work. Section A.1 addresses the input quantity indexes, including the calculation of capital cost. Section A.2 addresses our method for calculating TFP growth rates and trends.

A.1 Input Quantity Indexes

The growth rates of the input quantity indexes were defined by formulas. As noted in Section 3.2, these formulas involved subindexes measuring growth in the amounts of various inputs used. Major decisions in the design of such indexes include their form and the choice of input categories and quantity subindexes.

A.1.1 Index Form

Each regional input quantity index was of Törnqvist form.[4] The annual growth rate of each index was determined by the formula:

$$\ln\left(\frac{Input\ Quantities_t}{Input\ Quantities_{t-1}} \right) = \sum_j \frac{1}{2} \cdot \left(S_{j,t} + S_{j,t-1} \right) \cdot \ln\left(\frac{X_{j,t}}{X_{j,t-1}} \right). \qquad [9]$$

Here in each year t,

$Input\ Quantities_t$ = Input quantity index

$X_{j,t}$ = Quantity subindex for input category j

$S_{j,t}$ = Share of input category j in applicable total cost.

It can be seen that the growth rate of the index is a weighted average of the growth rates of the quantity subindexes. Each growth rate is calculated as the logarithm of the ratio of the quantities in successive years. For the output quantity index, weights are equal to the share of each quantity subindex's cost elasticity in the sum of cost elasticities for all outputs. Cost elasticities were estimated in our econometric work. For the input quantity indexes, data on the average shares of each input in the aggregate applicable total cost of sampled distributors during these years are the weights.

A.1.2 Output Quantity Subindexes

Output quantity subindexes were total gas delivery customers and gas delivery volumes.

A.1.3 Input Quantity Subindexes

The quantity subindex for labor was the ratio of the aggregate labor expenses to a BLS index of regional labor cost trends. The quantity subindex for other O&M inputs was the ratio of aggregate expenses for other O&M inputs to the GDPPI. The approach to quantity trend measurement taken in each case relies on the theoretical result that the growth rate in the cost of any class of input *j* is the sum of the growth rates in appropriate input price and quantity indexes for that input class. Thus,

$$growth\,Input\ Quantities_j = growth\,Cost_j - growth\,Input\ Prices_j. \qquad [10]$$

The quantity subindexes for capital are discussed immediately below.

A.1.4 Capital Cost

A service price approach was chosen to measure capital cost. This approach has a solid basis in economic theory and is widely used in scholarly empirical work.[5] It facilitates the aggregation for purposes of industry TFP research of cost data for utilities with different plant vintages.

In the application of the general method used in this study, the cost of a given class of utility plant *j* in a given year *t* ($CK_{j,t}$) is the product of a capital service price index ($WKS_{j,t}$) and an index of the capital quantity at the end of the prior year (XK_{t-1}).

$$CK_{j,t} = WKS_{j,t} \cdot XK_{j,t-1}. \qquad [11]$$

Each capital quantity index is constructed using inflation-adjusted data on the value of utility plant. Each service price index measures the trend in the hypothetical price of capital services from the assets in a competitive rental market. In our gas distribution research for BoGas, there is only one category of plant: gas plant.

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[4] For seminal discussions of this index form see Törnqvist (1936) and Theil (1965).

[5] See Hall and Jorgensen (1967) for a seminal discussion of the service price method of capital cost measurement.

In constructing indexes we took 1983 as the benchmark or starting year. The values for these indexes in the benchmark year are based on the net value of plant as reported in the USR. We estimated the benchmark year (inflation adjusted) value of net plant by dividing this book value by a "triangularized" weighted average of the values of an index of utility asset prices for a period ending in the benchmark year. Values were considered for a series of consecutive years with length equal to the lifetime of the relevant plant category. A triangularized weighting gives greater weight to more recent values of this index, reflecting the notion that more recent plant additions have a disproportionate impact on book value.[6] The asset-price index (WKA_t) was the applicable regional Handy-Whitman index of utility construction costs for the relevant asset category.[7]

The following formula was used to compute subsequent values of the capital quantity index:

$$XK_{j,t} = (1 - d) \cdot XK_{j,t-1} + \frac{VI_{j,t}}{WKA_{j,t}}. \qquad [12]$$

Here, the parameter d is the economic depreciation rate and VI_t is the value of gross additions to utility plant.

The economic depreciation rate was calculated as a weighted average of the depreciation rates for the structures and equipment used in the applicable industry. The depreciation rate for each structure and equipment category was obtained from the Bureau of Economic Analysis (BEA) of the U.S. Department of Commerce. The weights were based on net stock value data drawn from the same source.

The full formula for a capital service price index is:

$$WKS_t = \left(CK^{taxes}_{j,t} / XK_{j,t-1}\right) + r_t \cdot WKA_{j,t-1} + d \cdot WKA_{j,t} - \left(WKA_{j,t} - WKA_{j,t-1}\right). \qquad [13]$$

The four terms in this formula correspond to the four components of capital cost in a competitive industry. These are: taxes, the opportunity cost of capital, depreciation, and

[6] For example, in a triangularized weighting of 20 years of index values, the oldest index value has a weight of 1/210, the next oldest index has a value of 2/210, and so on. 210 is the sum of the numbers from 1 to 20. A discussion of triangularized weighting of asset price indexes is found in Stevenson (1980).

[7] These data are reported in the *Handy-Whitman Index of Public Utility Construction Costs*, a publication of Whitman, Requardt and Associates.

capital gains.[8] Here, $CK_{j,t}^{taxes}$ is total tax payments. The term r_t is the cost of funds. As a proxy for this we employ the user cost of capital for the U.S. economy.[9] This reflects returns on equity as well as interest rates. We calculate the user cost of capital using data in the National Income and Product Accounts (NIPA). The accounts are published by the BEA in its *Survey of Current Business* series. Capital gains are smoothed using a three-year moving average.

A.1.5 Output and Input Quantity Results

Detailed input quantity results can be found in Table 5 and 6. It can be seen that gas customers in the Northeast grew by 1.1% per annum while delivery volumes grew by 2.5% per annum, in average, over the 1990-2000 sample period. The index of output quantity grew by an average for 1.4% annually over this period. Turning to input

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[8] The opportunity cost of capital is sometimes called the cost of funds.

[9] The U.S. economy user cost of capital is not directly observable, but it can be measured by applying two economic relationships. The first economic pertains to the National Income and Products Accounts (NIPA) definitions of Gross Domestic Product (GDP) and the cost of inputs used by the U.S. economy. In the NIPA, the total cost of the U.S. economy inputs is equal to GDP. At the economy-wide level there are two inputs: labor and capital. Therefore the total cost of capital is equal to GDP less Labor Compensation (CL), or:

$$CK = GDP - CL \tag{1}$$

where CK represents the total cost of capital. The second relationship is between the total cost of capital and the components of the capital price equation. The total cost of capital is equal to the product of the quantity of capital input and the price of capital input, or:

$$CK = P_k \cdot K \tag{2}$$

where P_k represents the price and K the quantity of capital input. The price of capital can be decomposed into the price index for new plant and equipment (J), the opportunity cost of capital (r), the rate of depreciation (d), the inflation rate for new plant and equipment (l), and the rate of taxation on capital (t):

$$P_k = J \cdot (r + d - l + t) \tag{3}$$

Combining (2) and (3) one obtains the relationship:

$$\begin{aligned} CK &= J \cdot (r + d - l + t) \cdot K \\ &= r \cdot J \cdot K + d \cdot J \cdot K - l \cdot J \cdot K + t \cdot J \cdot K \\ &= r \cdot VK + D - l \cdot VK + T \end{aligned} \tag{4}$$

where D represents the total cost of depreciation, T total indirect business taxes and corporate profits taxes, and VK the current cost of plant and equipment net stock. Combining (1) and (4), one can derive the following equation for the opportunity cost of capital:

$$r = (GDP - CL - D - T + l \cdot VK) / (VK) \tag{5}$$

GDP, labor compensation, depreciation, and taxes are reported annually in the NIPA. The current cost of plant and equipment net stock and the inflation rate for plant and equipment are not reported in the NIPA, but are reported in <u>Fixed Reproducible Tangible Wealth in the United States</u>.

Table 5

Output Quantity Index: Northeast Gas Distributors

	Output Quantity Index	Retail Customers	Total Retail Deliveries
1990	1.000	1.000	1.000
1991	1.007	1.008	1.004
1992	1.046	1.016	1.144
1993	1.067	1.025	1.210
1994	1.080	1.037	1.226
1995	1.106	1.048	1.310
1996	1.108	1.051	1.307
1997	1.135	1.067	1.376
1998	1.126	1.087	1.258
1999	1.133	1.092	1.270
2000	1.152	1.113	1.285
Average Annual Growth Rate 1990-2000	1.42%	1.07%	2.51%

Table 6

Input Quantity Index:
Northeast Gas Distributors

	Input Quantity Index	Capital	Labor	Other O&M
1990	1.000	1.000	1.000	1.000
1991	1.024	1.032	0.968	1.089
1992	1.035	1.053	0.967	1.078
1993	1.052	1.078	0.970	1.093
1994	1.060	1.100	0.969	1.061
1995	1.066	1.125	0.908	1.101
1996	1.078	1.145	0.895	1.127
1997	1.066	1.165	0.860	1.022
1998	1.058	1.181	0.829	0.956
1999	1.067	1.194	0.862	0.906
2000	1.093	1.209	0.766	1.178
Average Annual Growth Rate 1990-2000	0.89%	1.89%	-2.66%	1.64%

quantities, it can be seen that the quantity of capital services grew by about 1.9% annually. The quantity of labor services fell by 2.7% annually, while the quantity of other O&M inputs rose by 1.6%. These results probably reflect some substitution of capital and other O&M inputs for labor during the sample period.

A.2 TFP Growth Rates and Trends

The annual growth rate in the TFP index is given by the formula

$$\ln\left(\frac{TFP_t}{TFP_{t-}}\right) = \ln\left(\frac{\textit{Output Quantities}_t}{\textit{Output Quantities}_{t-1}}\right) - \ln\left(\frac{\textit{Input Quantities}_t}{\textit{Input Quantities}_{t-1}}\right). \qquad [14]$$

The results featured in Section 2 are for the long-run trends of the indexes. Since the index formulas involve annual growth rates, some method is needed to calculate long run trends from the annual growth rates. The long run trend in each TFP index was computed using the formula

$$trend\,TFP_t = \frac{\sum_t {}_{1990}^{2000} \ln\left(\frac{TFP_t}{TFP_{t-1}}\right)}{10} = \frac{\ln\left(\frac{TFP_{2000}}{TFP_{1990}}\right)}{10}. \qquad [15]$$

It can be seen that the long run trend is the average annual growth rate during the years of the sample period. The reported long run trends in other indexes and subindexes were computed analogously.

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Exhibit KEDNE/LRK-3

THE COST PERFORMANCE OF BOSTON GAS

Pacific Economics Group
Economic and Litigation Consulting

THE COST PERFORMANCE OF BOSTON GAS

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TABLE OF CONTENTS

1. Introduction and Summary

1.1 Introduction

Statistical benchmarking has in recent years become a widely used tool in the assessment of utility performance. Managers look to benchmarking studies for indications of how well their companies are doing. Benchmarking also plays a growing role in regulation. Such studies can, for example, be used to assess the reasonableness of costs and consumer dividends at the start of multiyear rate plans.

Appraisals of utility performance are facilitated by the extensive data that utilities report to regulators and industry associations. However, accurate appraisals are still challenging. There are important differences between companies in the character of services provided, the overall scale of operations, the prices of production inputs, and other business conditions that influence their cost. Data are unavailable for many companies and do not cover all relevant business conditions where they are available.

Pacific Economics Group LLC ("PEG") personnel have been active for several years in statistical benchmarking research for utilities. We pioneered the use of scientific benchmarking in U.S. regulation and have testified on our work in several proceedings. Boston Gas (BoGas) is preparing a multiyear rate plan for its gas distribution services. It has commissioned PEG to measure its overall cost efficiency. We appraised its efficiency using econometric cost modeling.

This paper is a report on our benchmarking work for gas distribution. Following a brief summary of the work, Section 2 discusses the database used in the study and our calculation of distribution cost. Our econometric work is discussed in Section 3. Additional, more technical details of the research are presented in the Appendix.

1.2 Summary of Research

1.2.1 Definition of Cost

Our research addressed the efficiency of local gas distribution companies (LDCs) in managing the total cost of their distribution operations. Gas distribution services are defined to include the gas delivery, customer account and customer information services provided by LDCs. We do not address the cost of gas procurement services. The total cost of distribution services comprises the cost of plant ownership, operation, and maintenance.

1.2.2 The Sample

The econometric research was based on a sample of data for 43 distributors. The focus of benchmarking was the 1993-2000 period.

1.2.3 Econometric Research

The gas distribution cost performance of BoGas was appraised using an econometric cost model. Guided by economic theory, we developed a mathematical model in which the cost of gas distribution is a function of some quantifiable business conditions. The parameters of the model were estimated statistically using data on the historical costs of LDCs and the business conditions they faced. All key parameters were plausibly signed and highly significant.

We used the model to predict the average total cost of gas distribution services for BoGas given the business conditions it faced. The Company was found to face some challenging conditions in its efforts to contain gas distribution cost. For example, BoGas is not a combined gas and electric utility. The Company faces high prices for labor services and plant construction, and our results also show that there are special cost pressures from operating in the Northeast. It also has relatively more cast-iron main than any gas distributor in our sample.

BoGas's gas distribution cost was about 27% below the value predicted by the cost model, on average, from 1993 to 2000. This difference was statistically significant. We therefore conclude that BoGas is a significantly superior cost performer.

2. DATA ISSUES

2.1 Data

The primary source of the data used in our gas distribution cost research changed over the full sample period used in our benchmarking work. The *Uniform Statistical Report* (USR) was the primary source for the earliest years. Gas utilities are asked to file these reports annually with the American Gas Association (AGA). USR data for some variables are aggregated and published annually by the AGA in *Gas Facts.*

USRs are unavailable for many distributors. Many do not file complete USRs. Some LDCs that do file them do not release them to the public. The development of a satisfactory sample therefore required us to obtain basic cost and quantity data from alternative sources including, most notably, reports to state regulators. These reports often use as templates the Form 2 report that interstate gas transmission companies are required to file with the Federal Energy Regulatory Commission. Other sources of data were also used in the research. These included DRI/McGraw Hill; Whitman, Requardt & Associates; the Bureau of Economic Analysis ("BEA") of the U.S. Department of Commerce; and the Bureau of Labor Statistics ("BLS") of the U.S. Department of Labor.

Our econometric cost model is based on quality data for 43 gas distributors over the 1993 to 2000 period. The sample includes most of the nation's larger distributors.

The sampled distributors grouped by region are listed in Table 1. It can be seen that the regional distribution of sampled LDCs is somewhat uneven. In particular, the northeast accounts for 40% of the sampled companies, but accounts for only 23% of U.S. gas end users. Texas accounts for only 2% of the sample, but for 7% of gas end users. The table also indicates that the sampled LDCs served about 52% of all gas end users in the United States.

Table 1

SAMPLE FOR THE GAS DISTRIBUTION ECONOMETRIC RESEARCH

Region	Company	Number of Customers (2000)
Northeast		
	Boston Gas	542,792
	Brooklyn Union Gas	1,191,679
	Central Hudson Gas & Electric	63,851
	Commonwealth Gas	243,853
	Connecticut Energy	164,012
	Connecticut Natural Gas	155,641
	Consolidated Edison	1,048,357
	New Jersey Natural Gas	414,620
	Niagara Mohawk	548,075
	Orange & Rockland Utilities	118,718
	PECO	430,842
	People's Natural Gas	353,715
	PG Energy	155,992
	Providence Energy	172,965
	Public Service Electric & Gas	1,621,128
	Rochester Gas & Electric	285,944
South Atlantic		
	Atlanta Gas Light	1,530,000
	Baltimore Gas & Electric	595,239
	Public Service Company of North Carolina	357,736
	Washington Gas Light	868,362

Region	Company	Number of Customers (2000)
North Central		
	Citizens Gas & Coke	265,450
	Consumers Power	1,594,484
	East Ohio Gas	1,234,854
	Illinois Power	399,361
	Interstate Power	50,270
	Madison G & E	113,781
	North Shore Gas	149,781
	Northern Illinois Gas	1,962,228
	Peoples Gas Light & Coke	840,560
	Wisconsin Gas	540,676
	Wisconsin Power & Light	157,077
South Central		
	Alabama Gas	465,656
	Louisville Gas & Electric	297,717
	Oklahoma Natural Gas	757,688
Southwest		
	Enserch	1,415,296
	Mountain Fuel Supply	705,878
	Southwest Gas	1,289,046
Northwest		
	Cascade Natural Gas	193,160
	Northwest Natural Gas	510,686
	Washington Natural Gas	580,283
California		
	Pacific Gas & Electric	3,818,679
	San Diego Gas & Electric	756,053
	Southern California Gas	5,008,579
Total for Sample		33,970,764
Industry Total *		64,804,630
Percentage of U.S. Total		52.4%

*Source For US Total: U.S. Energy Information Administration, *Natural Gas Annual 2000*

2.2 Definition of Cost

2.2.1 Applicable Total Cost

Cost figures play an important role in our benchmarking methods. The applicable total cost of gas distribution was calculated as gas operation and maintenance ("O&M") expenses less gas production and procurement expenses plus total gas plant capital cost and a share of any common costs. The operations corresponding to this definition of cost include gas delivery, customer account, and customer information and other customer services of LDCs.

2.2.2 Cost Decomposition

Our benchmarking methods involve the decomposition of cost into three major input categories: capital services, labor services, and non-labor O&M inputs. The cost of gas delivery labor was defined as the sum of O&M salaries and wages and pensions and other employee benefits. The cost of other O&M inputs was defined to be O&M expenses net of these labor costs and of gas production and procurement expenses. This category includes the services of contract workers, insurance, real estate rents, equipment leases, and miscellaneous materials.

The study used a service price approach to measuring the cost of plant ownership that is based on the economic value of utility plant. Under this approach, the cost of capital is the product of a capital quantity index and the price of capital services. The cost of capital thus calculated includes depreciation, tax expenses, the opportunity cost of plant ownership, and capital gains. This method has a solid basis in economic theory and is well established in the scholarly literature. It controls in a precise and standardized way for differences between utilities in the age of their plants. Further details of our capital cost calculations are provided in Section A.1 of the Appendix.

3. ECONOMETRIC RESEARCH

3.1 An Overview of the Method

This section provides a substantially non-technical account of the econometric approach to benchmarking employed in this study. Additional, more technical details of the work are reported in the Appendix.

A mathematical model called a cost function was specified. Cost functions represent the relationship between the cost of a utility and quantifiable business conditions in its service territory. Business conditions are defined as aspects of a company's operating environment that influence its activities but cannot be controlled.

Economic theory was used to guide cost model development. We posited that the actual total cost (C_i) incurred by company, *i*, in service provision is the product of minimum achievable cost (C_i^*) and an efficiency factor ($efficiency_i$). This assumption can be expressed logarithmically as

$$\ln C_i = \ln C_i^* + \ln efficiency_i .^1 \qquad [1]$$

The term ln indicates the natural log of a variable.

According to theory, the minimum total cost of an enterprise is a function of the amount of work it performs and the prices it pays for capital and labor services and other inputs to its production process. Theory also provides some guidance regarding the nature of the relationship between these business conditions and cost. For example, cost is apt to be higher the higher are input prices and the greater is the amount of work performed.

Here is a simple example of a minimum total cost function for gas distribution that conforms to cost theory.

$$\ln C_{i,t}^* = a_0 + a_1 \cdot \ln N_{i,t} + a_2 \cdot \ln W_{i,t} + u_{i,t} . \qquad [2]$$

[1] The logarithm of the product of two variables is the sum of their individual logarithms.

For each firm i in year t, the variable $N_{i,t}$ is the number of customers that the company serves. It quantifies one dimension of the work that it performs. The variable $W_{i,t}$ is the wage rate that the company pays. The wage rate and delivery volume are the measured business conditions in this cost function.

The term $u_{i,t}$ is the error term of the cost function. This term reflects errors in the specification of the model, including problems in the measurement of output and other business condition variables and the exclusion from the model of relevant business conditions. It is customary to assume a specific probability distribution for the error term that is determined by additional parameters, such as mean and variance.

Combining the results of Equations [1] and [2] we obtain the following model of cost:[2]

$$\ln C_{i,t} = a_0 + a_i \ln N_{i,t} + a_2 \ln W_{i,t} + e_{i,t}. \qquad [3]$$

Here the *actual* (not minimum) total cost of a utility is a function of the two measured business conditions. The terms a_0, a_1, and a_2 are model parameters. Their values are assumed to be constant across companies and over some period of time. The a_0 parameter captures the efficiency factor for the average firm in the sample as well as the value of a_0 from Equation [3], the minimum total cost function. The values of a_1 and a_2 determine the effect of the two measured business conditions on cost. If the value of a_2 is positive, for instance, an increase in wage rates will raise cost.

[2] Here is the full logic behind this result:

$$\begin{aligned}
\ln C_{i,t} &= \ln C^*_{i,t} + \ln efficiency_i \\
&= \left(a_0 + a_1 \ln N_{i,t} + a_2 \ln W_{i,t} + u_{i,t}\right) + \ln efficiency_i \\
&= \left(a_0 + \ln efficiency^{average}\right) + a_1 \ln N_{i,t} + a_z \ln W_{i,t} \\
&\quad + \left[u_i + \left(\ln efficiency_i - \ln efficiency^{average}\right)\right] \\
&= a_0 + a_i \ln N_{i,t} + a_2 \ln W_{i,t} + e_{i,t}
\end{aligned}$$

The term $e_{i,t}$ is the error term for equation [3]. We assume that it is a random variable. It includes the error term from the minimum total cost function. It also reflects the extent to which the Company's efficiency factor differs from the sample norm.

A branch of statistics called econometrics has developed procedures for estimating parameters of economic models. Cost model parameters can be estimated econometrically using historical data on the costs incurred by utilities and the business conditions that they faced. For example, a positive estimate for a_2 would reflect the fact that the cost reported by sampled companies was typically higher when higher wages were paid to employees.

Numerous statistical methods have been established in the econometrics literature for estimating parameters of economic models. In choosing among these, we have been guided by the desire to obtain the best possible model for cost benchmarking. Econometric methods are also useful in selecting business conditions for the model. Tests are available for the hypothesis that the parameter for a business condition variable equals zero. Variables were excluded from the model when such hypotheses could not be rejected.

A cost function fitted with econometric parameter estimates may be called an <u>econometric cost benchmark model</u>. We can use such a model to predict a company's cost given values for the variables that represent the business conditions that the company faced. Returning to our simple example, we might predict the (logged) cost of BoGas in period *t* as follows:[3]

$$\ln \hat{C}_{BoGas,t} = \hat{a}_0 + \hat{a}_1 \cdot \ln N_{BoGas,t} + \hat{a}_2 \cdot \ln W_{BoGas,t}. \quad [4]$$

Here $\hat{C}_{BoGas,t}$ denotes the predicted cost of the Company in period t, $N_{BoGas,t}$ is the number of customers it served, and $W_{BoGas,t}$ is the wage rate that it paid. The $\hat{a}_0$, $\hat{a}_1$, and $\hat{a}_2$ terms are parameter estimates. Notice that in this model the cost benchmark reflects, through the estimate of parameter a_0, the *average* efficiency of the sampled utilities.

[3] Since this is a predicted equation using estimated parameters there is no error term.

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Consider, now, that if the parameter estimates are unbiased and the expected value of $u_{i,t}$ is zero, the expected value of the percentage difference between the company's actual cost and that predicted by the model is the percentage difference between the efficiency factor of BoGas and that of the sample mean firm.

$$\ln\left(C_{BoGas,t} \big/ \hat{C}_{BoGas,t}\right) = \ln\left(\text{efficiency}_{BoGas} \big/ efficiency^{average}\right). \qquad [5]$$

This percentage difference is a measure of the company's cost performance.

A number like that generated by the cost benchmark model in [5] constitutes our best estimate of the company's cost given the business conditions that it faces. This is an example of a point prediction. An important characteristic of the econometric approach to benchmarking is that the statistical results provide information about the *precision* of such point predictions. According to econometric theory, precision is greater the lower is the variance of the model's prediction error. The variance of the prediction error can be estimated using a well-established formula. The formula shows that the precision of cost model predictions is greater to the extent that:

1) The model is more successful in explaining the variation in cost in the sample
2) The size of the sample is larger
3) The number of business condition variables included in the model is smaller
4) The business conditions of sample companies are more varied
5) The business conditions of the subject company are closer to those of the typical firm in the sample

3.2 Business Condition Variables

3.2.1 Output Quantity Variables

As noted above, economic theory suggests that quantities of work performed by utilities should be included in our cost model as business condition variables. There are two output quantity variables in our model: the number of retail customers and total throughput. We expect cost to be higher for higher values of each of these workload measures.

3.2.2 Input Prices

Cost theory also suggests that the prices paid for production inputs are relevant business condition variables. In this model, we have specified input price variables for capital, labor, and other O&M inputs.[4] We expect cost to be higher as the values of these price variables increase.

The labor price variable used in this study was constructed by PEG using data from the BLS. National Compensation Survey ("NCS") data for 1998 were used to construct average wage rates that correspond to each LDC's service territory. The wage levels were calculated as a weighted average of the NCS pay level for each job category using weights that correspond to the Electric, Gas, and Sanitary (EGS) sector for the U.S. as a whole. Values for other years were calculated by adjusting the 1998 level for changes in the Employment Cost Index for the EGS sector over the 1993-2000 period.

Prices for other O&M inputs are assumed to be the same in a given year for all companies. They are escalated by growth in the GDP-PI. Our general approach to the computation of a price index for capital services is described in Section 2.2. Further details of this calculation are found in the Appendix.

3.3 Other Business Conditions

Five additional business condition variables are included in the cost model. One is the percentage of distribution main not made of cast iron, calculated from American Gas Association data. Cast iron pipes were common in gas system construction in the early days of the industry. It is more heavily used in the older distribution systems, which tend to be in the eastern U.S. Greater use of cast iron typically involves both higher maintenance and replacement costs. A higher value for this variable means that a company owns fewer cast iron mains and has lower expected costs. Hence, we would expect the sign for this coefficient to be negative.

[4] The price index for other O&M inputs doesn't appear in the estimated parameter tables due to the imposition of the linear homogeneity restriction predicted by economic theory.

A second additional business condition variable is the number of power distribution customers served by the utility. This variable is intended to capture the extent to which the company has diversified into power distribution. Such diversification will typically lower cost due to the ability to share inputs (e.g., personnel, computer systems, meter readers) between the two services. Higher values for this variable indicate greater levels of diversification. We would therefore expect the value of this coefficient to be negative.

A third business condition was a dummy variable for distributors that operate in territories that are subject to frequent earthquakes. Systems in these territories may have to be designed differently to withstand earthquakes. Because these design differences are likely to entail additional costs, the coefficient on this variable is expected to be positive.

The model also included a dummy variable for distributors operating in the northeastern U.S. Previous econometric studies for BoGas have found that Northeast operations are associated with higher costs, even after controlling for factors like higher input prices. This coefficient is therefore expected to be positive. The northeast dummy takes a value of 1 for every distributor headquartered in the New England, New York, Pennsylvania or New Jersey and zero for all other companies.

Finally, the model included a PBR dummy variable for BoGas. This variable took a value of one for BoGas during the years when it operated under PBR (1997-2000) and zero for other years and for every other company. Because PBR is expected to lower costs by strengthening performance incentives, this coefficient was expected to be negative.

The model also contains a trend variable. It permits predicted cost to shift over time for reasons other than changes in the specified business conditions. A trend variable captures the net effect on cost of diverse conditions, including technological change. It may also reflect the failure of the included business condition variables to properly measure the trends in relevant cost drivers. The model may, for instance, exclude an important cost driver or do a poor job of measuring such a driver. The trend variable might then capture the impact on cost of the trend in the driver.

3.4 Business Conditions of BoGas

Table 2 compares the average values over the 1993-2000 period of cost model business conditions for BoGas to the sample mean values of these variables. It can be seen that the average total cost of BoGas was just over 80% of the sample mean. Meanwhile, the number of customers served by BoGas was about 70% of the mean and its throughput was just below 80% of the mean.

Turning next to input prices, the table shows that BoGas had labor prices 13% above the sample mean. Its capital service price was about 9% above the mean.

Prices for other inputs were assumed to be the same across the sampled companies. This simplifying assumption may well distort results for BoGas. After all, it is quite possible that a region with high labor and construction costs also has higher average prices for other production inputs, especially those that are intensive in the use of local labor.

Regarding the other business conditions, note first that BoGas's percentage of gas distribution main that is not made of cast iron was well below the sample mean. In fact, BoGas had the most cast-iron intensive system in our sample, representing about 44% of main. This was more than twice the average share of cast iron main for the sample (17%) and reflects the age of the BoGas distribution network.

Note, finally, that BoGas has no power distribution customers. This has limited its opportunity to realize potential scope economies by sharing inputs with other utility services.

3.5 Econometric Results

3.5.1 Estimation Results

Estimation results for the cost model are reported in Table 3. The parameter values for the five additional business conditions and for the first order terms of the translogged variables are elasticities of the cost of the sample mean firm with respect to the basic variable. The first order terms are the terms that do not involve squared values of business condition variables or interactions between different variables. The table shades the results for these terms for reader convenience.

Table 2

Average Values of Variables in the Benchmarking Study: Gas Delivery

Variable	Units	U.S. Sample Average	Boston Gas	Boston Gas/ Sample Mean
Gas Delivery Cost	1,000 U.S. Dollars	380,027	311,651	0.82
Number of Customers	Customers	742,764	522,947	0.70
Total Throughput	mdkth	181,144	141,966	0.78
Price of Capital Services	Index Number	16.25	17.67	1.09
Price of Labor Services	Dollars per Employee	35,132	39,818	1.13
Price of Materials	Index Number	1.13	1.13	1.00
Number of Electric Customers	Customers	432,511	0	0.00
Percent of Main not Cast Iron	Percent	83.02%	56.14%	0.68
Earthquake Dummy	Binary	0.186	0.000	0.00
NE Dummy	Binary	0.372	1.000	2.69

Table 3

Translog Cost Function Regression Results:
Gas Delivery

VARIABLE KEY*

L= Labor Price
K= Capital Price
N= Number of Customers
YV= Total Throughput
EC= Number of Electric Customers
NI= % of Main that is Non-cast Iron
EQ= Earthquake Dummy Variable
NE= Northeast Dummy
BG= Boston Gas PBR Dummy

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC	EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC
L	0.202	60.15	EC	-0.010	-7.50
LL	-0.101	-2.19			
LK	0.010	0.41	NI	-0.210	-4.23
LN	0.014	1.58			
LYV	-0.023	-2.60	EQ	0.016	3.75
K	0.648	141.21	NE	0.059	9.11
KK	0.090	3.38			
KN	-0.028	-2.61	BG	-0.003	-3.92
KYV	0.038	3.54			
N	0.658	20.82	Constant	8.015	356.38
NN	-0.439	-6.41			
NYV	0.452	6.44	Trend	-0.005	-1.46
YV	0.210	6.32	System Rbar-Squared	0.975	
YVYV	-0.512	-6.83			

* Data for all variables were logged and mean-scaled prior to model estimation

The tables also report the values for the corresponding asymptotic t ratios. These were also generated by the estimation program and were used to assess the range of possible values for parameters that are consistent with the data. A parameter estimate is deemed statistically significant if the hypothesis that the true parameter value equals zero is rejected. This statistical test requires the selection of a critical value for the asymptotic *t* ratio. In this study, we employed critical values that are appropriate for a 90% confidence level given a large sample. The critical value was 1.645.

Examining the results in Table 3, it can be seen that the cost function parameter estimates were plausible as to sign and magnitude. With regard to the first order terms of the translogged variables, cost was found to be higher the higher were input prices and output quantities. At the sample mean, a 1% increase in the number of customers raised cost by 0.66%. A 1% hike in throughput raised cost by about 0.21%. The sum of those elasticities was about 0.87%. The number of customers served was clearly the dominant output-related cost driver.

The sum of the output elasticities is a common indicator of economies of scale. A sum less than one is an indicator that scale economies can be realized from balanced output growth for a firm of sample mean size. Since TFP growth depends in part on scale economies, this also means that it can differ from region to region of the U.S. due in part to differences in the pace of output growth.

Turning to results for the input prices, it can be seen that the elasticity of cost with respect to the price of capital services was 0.65%. This was more than three times the estimated elasticity of the price of labor. This reflects the capital intensiveness of the gas distribution business.

The coefficients on the additional business condition variables were also sensible and, with the exception of the trend variable, were statistically significant.

- Cost was lower as the percentage of distribution mains not made with cast iron increased.

- Cost was lower as the number of electric customers served by a distributor increased.
- Cost was higher for distributors operating in the Northeast.
- Cost was higher for distributors operating in territories with frequent earthquakes.
- The coefficient on the PBR dummy was –0.3%; this implies that, after controlling for each of the other business conditions in the model, BoGas's costs declined by 0.3% during the years when PBR was in effect.
- The estimate of the trend variable parameter was –0.005 and was not significant.

3.5.2 Econometric Benchmarking Results

Table 4 presents the results of our appraisals of BoGas's cost using the econometric model. The Company's average cost during the sample period was found to be about 27% below its predicted value. The hypothesis that the company was an average (or inferior) cost performer was rejected at the 99% confidence level. BoGas was therefore a significantly superior cost performer.

Table 4

Actual and Predicted Comprehensive Cost For Gas Distribution: 1993-2000 Boston Gas (U.S. $)

Actual Cost $1,000	Predicted Cost $1,000	Difference (%)	t-statistic
311,651	427,898	-27.2%	-5.59

APPENDIX:

FURTHER DETAILS OF THE BENCHMARKING RESEARCH

This section provides additional and more technical details of our benchmarking work. We first consider our method for computing capital cost. There follow treatments of our indexing and econometric work.

A.1 Capital Cost

A service price approach was chosen to measure the cost of plant ownership. This approach has a solid basis in economic theory and is widely used in scholarly empirical work.[5] In the application of the general methodology used in this study, capital cost in a given year t, CK_t, is the product of a capital service price index, WKS_t and a capital quantity index, XK_{t-1}.

$$CK_t = WKS_t \cdot XK_{t-1}. \qquad [6]$$

The service price index may be thought of as the annual cost (including the opportunity cost) of owning a unit of plant.

Each capital quantity index is constructed using inflation-adjusted data on the value of utility plant. Each service price index measures the trend in the hypothetical price of capital services from the assets in a competitive rental market. The price and quantity indexes require a consistent mathematical characterization of the process of plant deterioration.

In constructing the indexes we took 1983 as the benchmark or starting year for our gas distribution cost research. The values for these indexes in the benchmark year are based on the net value of plant as reported on the USR. We estimated the benchmark year (inflation adjusted) value of net plant by dividing the aggregate appropriate base year value by a "triangularized" weighted average of the values of an index of utility asset prices for a period ending in the

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[5] See Hall and Jorgensen (1967) for a seminal discussion of the service price method of capital cost measurement.

benchmark year equal to the lifetime of plant. A triangularized weighting gives greater weight to more recent values of this index, reflecting the notion that more recent plant additions have a disproportionate impact on the book value of plant.[6] The value of the asset-price index, WKA_t, is the applicable regional Handy-Whitman index of utility construction costs for the relevant asset category.[7]

The following formula was used to compute subsequent values of the capital quantity index:

$$XK_t = (1 - d) \cdot XK_{t-1} + \frac{VI_t}{WKA_t}. \qquad [7]$$

Here, the parameter, d, is the economic depreciation rate, VI_t is the value of gross additions to the utility plant and WKA_t is the index of utility plant asset prices.

The economic depreciation rate, d, was calculated as a weighted average of the depreciation rates for the structures and equipment used in the applicable industry. The depreciation rate for each structure and equipment category was obtained from the Bureau of Economic Analysis (BEA) of the U.S. Department of Commerce. The weights were based on net stock value data drawn from the same source.

The formula for the capital service price index, WKS_t, is:

$$WKS_t = \left(CK_t^{taxes} / XK_{t-1}\right) + r_t \cdot WKA_{t-1} + d \cdot WKA_t - \left(WKA_t - WKA_{t-1}\right). \qquad [8]$$

The four terms in this formula correspond to the four components of capital cost. These are: taxes, the opportunity cost of capital, depreciation, and capital gains.[8] Here, CK_t^{taxes} is the sum of total tax payments and franchise fees attributed to the LDC.[9] The term, r_t, is the user cost of capital for the U.S. economy.[10] PEG calculates this using data in the National Income and Product Accounts

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[6] For example, in a triangularized weighting of 20 years of index values, the oldest index value has a weight of 1/210, the next oldest index has a value of 2/210, and so on. 210 is the sum of the numbers from 1 to 20. A discussion of triangularized weighting of asset price indexes is found in Stevenson (1980).

[7] These data are reported in the *Handy-Whitman Index of Public Utility Construction Costs*, a publication of Whitman, Requardt and Associates.

[8] The opportunity cost of capital is sometimes called the cost of funds.

[9] Franchise fees are a part of O&M expenses in our TFP trend indexes.

[10] The U.S. economy user cost of capital is not directly observable, but it can be measured by applying two economic relationships. The first economic pertains to the National Income and Products Accounts (NIPA)

(NIPA). The accounts are published by the Department of Commerce in its Survey of Current Business series. Capital gains are smoothed using a three-year moving average.

A.2 Econometric Research

A.2.1 Form of the Cost Model

The functional form selected for this study was the translog.[11] This very flexible function is the most frequently used in econometric cost research, and by some account the most reliable of several available alternatives.[12] The general form of the translog cost function is:

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definitions of Gross Domestic Product (GDP) and the cost of inputs used by the U.S. economy. In the NIPA, the total cost of the U.S. economy inputs is equal to GDP. At the economy-wide level there are two inputs: labor and capital. Therefore the total cost of capital is equal to GDP less Labor Compensation (CL), or:

$$CK = GDP - CL \tag{1}$$

where CK represents the total cost of capital. The second relationship is between the total cost of capital and the components of the capital price equation. The total cost of capital is equal to the product of the quantity of capital input and the price of capital input, or:

$$CK = P_k \cdot K \tag{2}$$

where P_k represents the price and K the quantity of capital input. The price of capital can be decomposed into the price index for new plant and equipment (J), the opportunity cost of capital (r), the rate of depreciation (d), the inflation rate for new plant and equipment (l), and the rate of taxation on capital (t):

$$P_k = J \cdot (r + d - l + t) \tag{3}$$

Combining (2) and (3) one obtains the relationship:

$$\begin{aligned} CK &= J \cdot (r + d - l + t) \cdot K \\ &= r \cdot J \cdot K + d \cdot J \cdot K - l \cdot J \cdot K + t \cdot J \cdot K \qquad (4) \\ &= r \cdot VK + D - l \cdot VK + T \end{aligned}$$

where D represents the total cost of depreciation, T total indirect business taxes and corporate profits taxes, and VK the current cost of plant and equipment net stock. Combining (1) and (4), one can derive the following equation for the opportunity cost of capital:

$$r = {(GDP - CL - D - T + l \cdot VK)} \big/ {(VK)} \tag{5}$$

GDP, labor compensation, depreciation, and taxes are reported annually in the NIPA. The current cost of plant and equipment net stock and the inflation rate for plant and equipment are not reported in the NIPA, but are reported in Fixed Reproducible Tangible Wealth in the United States.

[11] The transcendental logarithmic (or translog) cost function can be derived mathematically as a second order Taylor series expansion of the logarithmic value of an arbitrary cost function around a vector of input prices and output quantities.

[12] See Guilkey (1983), et. al.

$$\ln C = a_0 + \sum_h a_h \ln Y_h + \sum_j a_j \ln W_j + \frac{1}{2}\left(\sum_h \sum_k g_{h,k} \ln Y_h \ln Y_k + \sum_j \sum_n g_{j,n} \ln W_j \ln W_n\right) + \sum_h \sum_j g_{i,j} \ln Y_i \ln W_j \qquad [9]$$

where Y_h denotes one of K variables that quantify output and the W_j denotes one of N input prices.

One aspect of the flexibility of this function is its ability to allow the elasticity of cost with respect to each business condition variable to vary with the value of that variable. The elasticity of cost with respect to an output quantity, for instance, may be greater at smaller values of the variable than at larger variables. This type of relationship between cost and quantity is often found in cost research.

Business conditions other than input prices and output quantities can contribute to differences in the costs of LDCs. To help control for other business conditions the logged values of some additional explanatory variables were added to the model in Equation [9] above.

The econometric model of cost we wish to estimate can then be written as:

$$\ln C = a_o + \sum_h a_h \ln Y_h + \sum_j a_j \ln W_j + \frac{1}{2}\left[\sum_h \sum_k g_{hk} \ln Y_h \ln Y_k + \sum_j \sum_n g_{jn} \ln W_j \ln W_n\right] + \sum_h \sum_j g_{ij} \ln Y_h \ln W_j + \sum_h a_h \ln Z_h + a_t T + e \qquad [10]$$

Here the Z_h's denote the additional business conditions, T is a trend variable, and e denotes the error term of the regression.

Cost theory requires a well-behaved cost function to be homogeneous in input prices. This implies the following three sets of restrictions:

$$\sum_{h=1}^{N} \frac{\partial \ln C}{\partial \ln W_h} = 1 \qquad [11]$$

$$\sum_{h=1}^{N} \frac{\partial^2 \ln C}{\partial \ln W_h \partial \ln W_j} = 0 \qquad \forall j = 1,\ldots, N \qquad [12]$$

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$$\sum_{h}^{N} \frac{\partial^2 \ln C}{\partial \ln Y_h \partial \ln Y_j} = 0 \qquad \forall j = 1,\ldots, K \qquad [13]$$

Imposing the above $(1+N+K)$ restrictions implied by Equations [21-23] allow us to reduce the number of parameters that need be estimated by the same amount.

Estimation of the parameters in Equation [20] is now possible but this approach does not utilize all information available in helping to explain the factors that determine cost. More efficient estimates can be obtained by augmenting the cost equation with the set of cost share equations implied by Shepard's Lemma. The general form of a cost share equation for a representative input price category, j, can be written as:

$$S_j = a_j + \sum_i g_{h,j} \ln Y_h + \sum_n g_{jn} \ln W_n \qquad [14]$$

We note that the parameters in this equation also appear in the cost model. Since the share equations for each input price are derived from the first derivative of the translog cost function with respect to that input price, this should come as no surprise. Furthermore, because of these cross-equation restrictions, the total number of coefficients in this system of equations will be no larger than the number of coefficients required to be estimated in the cost equation itself.

A.2.2 Estimation Procedure

We estimated this system of equations using a procedure first proposed by Zellner (1962).[13] It is well known that if there exists contemporaneous correlation between the errors in the system of regressions, more efficient estimates can be obtained by using a Feasible Generalized Least Squares (FGLS) approach. To achieve even a better estimator, PEG iterates this procedure to convergence.[14] Since we estimate these unknown disturbance matrices consistently, the estimators we eventually compute are equivalent to Maximum Likelihood Estimation (MLE).[15] Our estimates would thus possess all the highly desirable properties of MLE's.

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[13] See Zellner, A. (1962).

[14] That is, we iterate the procedure until the determinant of the difference between any two consecutive estimated disturbance matrices are approximately zero.

[15] See Dhrymes (1971), Oberhofer and Kmenta (1974), Magnus (1978).

Before proceeding with estimation, there is one complication that needs to be addressed. Since the cost share equations by definition must sum to one at every observation, one cost share equation is redundant and must be dropped.[16] This does not pose a problem since another property of the MLE procedure is that it is invariant to any such reparameterization. Hence, the choice of which equation to drop will not affect the resulting estimates.

A.2.3 Predicting Cost

We now turn our attention to the topic of predicting the level of a utility's cost given its specific values for the explanatory variables. Fitting our cost model with the econometric parameter estimates, we obtain an econometric model of distributor cost. This can then be used to predict the historical cost of an LDC given its values for the specified business controls. It is well known that the ability of the model to make accurate predictions depends, in part, on the characteristics of the data reported for the utility as compared to the sample averages. The closer the firm's data are to the sample averages, the more accurate is the model's prediction. Alternatively, the more the characteristics of the utility's data lie outside those of the sample means, the less reliable is its predicted cost.

It should be noted that the model specification was determined using the data for all sampled companies, including BoGas. However, to compute the model parameters and standard errors for the prediction required that the utility of interest be dropped from the sample when we estimated the coefficients in the predicting equation.[17] The standard error based on this "out-of-sample" prediction was then used to construct the hypothesis tests for cost efficiency.

[16] This equation can be estimated indirectly from the estimates of the parameters left remaining in the model.

[17] This implies that the estimates used in constructing the predicting equation will vary slightly from those reported in the study.

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COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
NINETEENTH SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL
D. T. E. 05-27

Date: June 30, 2005

Responsible: John E. Skirtich, Consultant (Revenue Requirements)

AG-19-27 Referring to the Company's response to Information Request AG-1-55, please itemize and quantify the amount of the Corporate Transport Aircraft costs, including capital costs, as well as operating costs assigned and / or allocated to Bay State Gas during the test year in this case.

Response: Please see Table AG-19-27 itemizing the Corporate Aircraft Department O&M costs allocated to BSG during the test year. No depreciation expense on the Corporate Aircraft was allocated to BSG during the test year.

Table AG-19-27

Gross Payroll	597.53
Materials & Supplies - General	17,116.60
Outside Services - Other	69,828.75
Maintenance & Structures	10,306.71
Rents - Other	2,094.72
Data Processing - Leased	16.97
Aircraft - Rents	36,550.57
Employee Expenses - Transportation	2,447.53
Employee Expenses - Meals & Entertainment	680.25
Dues & Memberships	47.73
Training	8,447.79
Other Expenses - General	2,135.22
Taxes - Gross Receipts	174.24
	150,444.61

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
TWENTY-SECOND SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL
D. T. E. 05-27

Date: June 30, 2005

Responsible: Stephen H. Bryant, President

AG-22-13 Please provide copies of all policies and procedures that govern the Company's collection practices. Include copies of all official policies, internal memos and training materials. If the Company uses any third party collection agents, please provide complete copies of all contracts governing the contracted services.

Response: Attachment AG-22-13 (a) is a copy of the Company's training materials and internal policies.

Attachment AG-22-13 (b) is a copy of the contract between NiSource and Alliance One for third party collections.

Attachment AG-22-13 (c) is a copy of the contract between NiSource and NCO for third party collections.

Attachment AG-22-13 (d) is a copy of the contract between NiSource and UCB for third party collections.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
TWENTY SECOND SET OF INFORMATION REQUESTS FROM THE
ATTORNEY GENERAL
D. T. E. 05-27

Date: June 30, 2005

Responsible: Joseph A. Ferro, Manager, Regulatory Policy and
James L. Harrison, Consultant (Cost Studies)

AG-22-14 Refer to Exhibit JAF-3, page 13. Does the SMBA allocation method replicate the way the Company procures its gas supplies to serve its various customer classes? Compare and contrast the actual resource procurement process to the assumptions underlying the SMBA.

Response: The Company does not procure its gas supplies to serve its individual rate classes. The Company's resource (supply and capacity) portfolio is modified periodically to insure reliable service to its firm sales (supply and capacity) and non-grandfathered transportation (capacity) customers. Since supply and capacity contracts have terms of varying length and since delivered supply alternatives are discrete in terms of size and timing, the resource portfolio is generally designed on a best cost rather than a least cost basis. However, inherent in the resource planning process are tradeoffs between high fixed cost delivered supplies with lower variable costs and low fixed cost delivered supplies with higher variable costs. The SMBA recognizes these same tradeoffs in its allocation of gas costs to customer classes.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
FIFTEENTH SET OF INFORMATION REQUESTS FROM THE D.T.E.

Date: June 30, 2005

Responsible: Joseph A. Ferro, Manager Regulatory Policy

AG-22-33: Please explain, in detail, how the Company determined the R-2 and R-4 bill determinants. Include all supporting documentation, workpapers, calculations and assumptions.

Response: The Company determined the R-2 and R-4 billing determinants as it determined all other rate class billing determinants. See the testimony of Joseph A. Ferro, Exhibit BSG/JAF-1 and all pertinent schedules.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
TWENTY-SECOND SET OF INFORMATION REQUESTS FROM ATTORNEY GENERAL
D. T. E. 05-27

Date: June 30, 2005

Responsible: Joseph A. Ferro, Manager Regulatory Policy

AG-22-46 Refer to the Company's responses to AG-9-8 and AG-9-10. Please explain why the relationship of the Indirect Gas rate and GAF rates is not the same. In other words why are the R-3/4 GAF rates lower than the G-40 through G-43 rates but the R3/4 Indirect GAF rates are higher than the G-40 through G-43 rates in some months. Explain how the class specific allocations were made for each season. Include an explanation of how the bad debt costs were allocated. Explain how the bad debt costs and revenues were reconciled for each CGA class.

Response: GAF rates are determined by allocating forecast demand and commodity costs to each rate class using the Market Based Allocation (MBA) methodology. These rates reflect the Company's forecast supply mix satisfying the firm demand of each rate class. Thus, these GAF rates reflect a current allocation of costs to each rate class.

On the other hand, indirect gas costs excluding production and storage ("P & S") are assigned uniformly across all rate classes, while the allocation of P & S costs are based on the Company's cost allocation study in it's last rate proceeding (DPU 95-104). Therefore although there is a direct relationship between direct and indirect gas costs on a total Company basis, the direct relationship does not exist by rate class.

Bad debt expense associated with gas cost collections is assigned uniformly across all rate classes. Bad debt costs and revenues associated with gas cost collections are reconciled on a total Company basis. Note that all CGA costs are reconciled on a total Company basis, not by rate class.

Direct gas costs, i.e. those costs associated with the forecast period, are allocated using the MBA method and based on annual dispatch and costs that is allocated to each season. This method assigns costs first by ranking the supply sources by the overall delivered cost (including commodity and demand) and then assigning the lowest cost pipeline gas first to the Company's system wide base load requirement. Fifty percent (50%) of base load costs are assigned to the Off-peak period and 50% to the Peak period. The remaining supplies satisfy the Company's requirements above base load. Each class is allocated their share of base load requirements on the average cost of this portion of the load curve and based on each class' base load use that makes up the total Company base load requirements. Then, the remaining supplies and associated costs needed to satisfy the system's demand above base load is assigned to each class on a daily basis using a proportional responsibility (PR) allocation method. Please see Mr. Harrison's testimony, Exhibit BSG/JLH-1 for a more detailed explanation of the MBA of allocating costs to each rate class.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
TWENTY-THIRD SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL
D. T. E. 05-27

Date: June 30, 2005

Responsible: Danny G. Cote, General Manager

SUPPLEMENTAL RESPONSE

AG-23-5 Please identify the manufacture by name, address and phone number of the unprotected coated steel mains that Company has replaced since 1990 in Brockton and Lawrence. Has the Company ever contacted the manufacturer of these unprotected coated steel pipes (or the company responsible for the coatings) regarding leaks, regardless of whether the Company submitted a formal warranty claim? Describe the results of any discussions and produce all documents related to contact with the manufacturer(s).

Response: We do not have records that identify the manufacturer of the coated unprotected pipe in the bay State system.

Supplemental response:

Over the years Bay State has purchased coated steel pipe using two different purchasing methodologies:

- For large quantities of pipe Bay State would order the pipe from a pipe mill, then have the pipe shipped to a coater for application of the coating.
- For small quantities of pipe Bay State would buy coated pipe directly from a manufacturer of from a distributor.

That said, the entire amount of unprotected coated pipe in the Bay State system was installed in the 1950’s and 1960’s. To the best of the Company’s knowledge, Bay State has no records that indicate which pipe mill or pipe coater it purchased from in any given year.

Finally, even if the Company did have records of pipe and coating purchases by year, it would have no way of telling which pipe was used for each discrete segment of main. Since Bay State has over 2000 miles of pre- and post-1970 pipe under cathodic protection, and approximately 106 miles of pre-1970 pipe which is coated but unprotected, without a data base that reconciles pipe purchases to specific main projects (which does not exist) there would still be no way to identify the manufacturer or coater of any specific street in the Bay State system that has coated unprotected main.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
TWENTY-FOURTH SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL
D. T. E. 05-27

Date: June 30, 2005

Responsible: Stephen H. Bryant, President

AG-24-2 Please refer to the NiSource - IBM Outsourcing Announcement of June 21, 2005 ("IBM Agreement"). Please provide all workpapers, calculations, data and assumptions supporting the Company's assertion that the IBM Agreement is worth $1.6 billion to IBM.

Response: As discussed at greater length in the Company's response to DTE-18-01, the Company notes that, due to the need for NiSource to incur significant costs in the first two years of the Outsourcing Agreement with IBM in order to achieve the longer-run savings over the life of the ten-year agreement, no significant positive net financial benefits will be realized by NiSource until, at the earliest, 2007, well beyond the test year and even beyond the end of the rate year. As such, the long-run financial impact of the Outsourcing Agreement is not relevant to this proceeding.

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D. T. E. 05-27

Date: June 30, 2005

Responsible: Stephen H. Bryant, President

AG-24-3 Please refer to the NiSource - IBM Outsourcing Announcement of June 21, 2005 (“IBM Agreement”). Please identify the amount of the $1.6 billion cost to NiSource that NiSource will allocate or assign to each NiSource subsidiary. Please provide all workpapers, calculations, data and assumptions supporting the Company’s answer. Please provide an explanation for each allocation or assignment, including to Bay State Gas Company (“Company”).

Response: Please see the Company’s response to DTE-18-01 and AG-24-02.

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D. T. E. 05-27

Date: June 30, 2005

Responsible: Stephen H. Bryant, President

AG-24-4 Please refer to the NiSource - IBM Outsourcing Announcement of June 21, 2005 ("IBM Agreement"). Please identify how much of the Company's allocated or assigned share of the $1.6 billion cost will the Company seek to recover from ratepayers. Please explain how the Company proposes to recover that amount from ratepayers.

Response: Please see the Company's response to DTE-18-01 and AG-24-02.

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RESPONSE OF BAY STATE GAS COMPANY TO THE
TWENTY-FOURTH SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL
D. T. E. 05-27

Date: June 30, 2005

Responsible: Stephen H. Bryant, President

AG-24-5 Please refer to the NiSource - IBM Outsourcing Announcement of June 21, 2005 ("IBM Agreement"). Please provide all workpapers, calculations, data and assumptions supporting the Company's assertion that the Agreement will deliver $530 million in operating and capital cost savings.

Response: Please see the Company's response to DTE-18-01 and AG-24-02.

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RESPONSE OF BAY STATE GAS COMPANY TO THE
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D. T. E. 05-27

Date: June 30, 2005

Responsible: Stephen H. Bryant, President

AG-24-6 Please refer to the NiSource - IBM Outsourcing Announcement of June 21, 2005 ("IBM Agreement"). Please identify the amount of the $530 million in operating and capital cost savings that NiSource will allocate or assign to each NiSource subsidiary. Please provide all workpapers, calculations, data and assumptions supporting the Company's answer.

Please provide an explanation for each allocation or assignment, including to the Company.

Response: Please see the Company's response to DTE-18-01 and AG-24-02.

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Date: June 30, 2005

Responsible: Stephen H. Bryant, President

AG-24-7 Please refer to the NiSource - IBM Outsourcing Announcement of June 21, 2005 (“IBM Agreement”). Please identify how much of the Company’s allocated or assigned share of the $530 million in savings will the Company pass along to its ratepayers. Please explain how the Company proposes to reflect that share of savings.

Response: Please see the Company’s response to DTE-18-01 and AG-24-02.

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D. T. E. 05-27

Date: June 30, 2005

Responsible: Stephen H. Bryant, President

AG-24-8 Please refer to the NiSource - IBM Outsourcing Announcement of June 21, 2005 (“IBM Agreement”). Please provide all workpapers, calculations, data and assumptions supporting the Company’s assertion that the Agreement will cost NiSource $35 million for a one-time severance expense.

Response: Please see the Company’s response to DTE-18-01 and AG-24-02.

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RESPONSE OF BAY STATE GAS COMPANY TO THE
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D. T. E. 05-27

Date: June 30, 2005

Responsible: Stephen H. Bryant, President

AG-24-9 Please refer to the NiSource - IBM Outsourcing Announcement of June 21, 2005 (“IBM Agreement”). Please identify the amount of the $35 million severance expense that NiSource will allocate or assign to each NiSource subsidiary. Please provide all workpapers, calculations, data and assumptions supporting the Company’s answer. Please provide an explanation for each allocation or assignment, including to the Company.

Response: Please see the Company’s response to DTE-18-01 and AG-24-02.

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D. T. E. 05-27

Date: June 30, 2005

Responsible: Stephen H. Bryant, President

AG-24-10 Please refer to the NiSource - IBM Outsourcing Announcement of June 21, 2005 ("IBM Agreement"). Please identify how much of the Company's allocated or assigned share of the $35 million in severance expense will the Company seek to recover from its ratepayers. Please explain how the Company proposes to recover that share of expense.

Response: Please see the Company's response to DTE-18-01 and AG-24-02.

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Date: June 30, 2005

Responsible: Stephen H. Bryant, President

AG-24-11 Please refer to the NiSource - IBM Outsourcing Announcement of June 21, 2005 (“IBM Agreement”). Please provide all workpapers ,calculations, data and assumptions supporting the Company’s assertion that the Agreement will cost NiSource $35 million in transition costs.

Response: Please see the Company’s response to DTE-18-01 and AG-24-02.

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D. T. E. 05-27

Date: June 30, 2005

Responsible: Stephen H. Bryant, President

AG-24-12 Please refer to the NiSource - IBM Outsourcing Announcement of June 21, 2005 (“IBM Agreement”). Please identify the amount of the $35 million transition costs that NiSource will allocate or assign to each NiSource subsidiary. Please provide all workpapers, calculations, data and assumptions supporting the Company’s answer. Please provide an explanation for each allocation or assignment, including to the Company.

Response: Please see the Company’s response to DTE-18-01 and AG-24-02.

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RESPONSE OF BAY STATE GAS COMPANY TO THE
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D. T. E. 05-27

Date: June 30, 2005

Responsible: Stephen H. Bryant, President

AG-24-13 Please refer to the NiSource - IBM Outsourcing Announcement of June 21, 2005 ("IBM Agreement"). Please identify how much of the Company's allocated or assigned share of the $35 million in transition costs will the Company seek to recover from its ratepayers. Please explain how the Company proposes to recover that share of expense.

Response: Please see the Company's response to DTE-18-01 and AG-24-02.

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RESPONSE OF BAY STATE GAS COMPANY TO THE
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D. T. E. 05-27

Date: June 30, 2005

Responsible: Stephen H. Bryant, President

AG-24-14 Please refer to the NiSource - IBM Outsourcing Announcement of June 21, 2005 ("IBM Agreement"). Please provide all workpapers, calculations, data and assumptions supporting the Company's assertion that the Agreement will cost NiSource $50 million in governance costs.

Response: Please see the Company's response to DTE-18-01 and AG-24-02.

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RESPONSE OF BAY STATE GAS COMPANY TO THE
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D. T. E. 05-27

Date: June 30, 2005

Responsible: Stephen H. Bryant, President

AG-24-15 Please refer to the NiSource - IBM Outsourcing Announcement of June 21, 2005 ("IBM Agreement"). Please identify the amount of the $50 million in governance costs that NiSource will allocate or assign to each NiSource subsidiary. Please provide all workpapers, calculations, data and assumptions supporting the Company's answer. Please provide an explanation for each allocation or assignment, including to the Company.

Response: Please see the Company's response to DTE-18-01 and AG-24-02.

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D. T. E. 05-27

Date: June 30, 2005

Responsible: Stephen H. Bryant, President

AG-24-16 Please refer to the NiSource - IBM Outsourcing Announcement of June 21, 2005 ("IBM Agreement"). Please identify how much of the Company's allocated or assigned share of the $50 million in governance costs will the Company seek to recover from its ratepayers. Please explain how the Company proposes to recover that share of expense.

Response: Please see the Company's response to DTE-18-01 and AG-24-02.

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D. T. E. 05-27

Date: June 30, 2005

Responsible: Stephen H. Bryant, President

AG-24-17 Please refer to the NiSource - IBM Outsourcing Announcement of June 21, 2005 (“IBM Agreement”). Please provide all workpapers ,calculations, data and assumptions supporting the Company’s assertion that the Agreement will cost NiSource $21 million in non-cash pension expense.

Response: Please see the Company’s response to DTE-18-01 and AG-24-02.

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D. T. E. 05-27

Date: June 30, 2005

Responsible: Stephen H. Bryant, President

AG-24-18 Please refer to the NiSource - IBM Outsourcing Announcement of June 21, 2005 (“IBM Agreement”). Please identify the amount of the $21 million in non-cash pension expense that NiSource will allocate or assign to each NiSource subsidiary. Please provide all workpapers, calculations, data and assumptions supporting the Company’s answer. Please provide an explanation for each allocation or assignment, including to the Company.

Response: Please see the Company’s response to DTE-18-01 and AG-24-02.

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D. T. E. 05-27

Date: June 30, 2005

Responsible: Stephen H. Bryant, President

AG-24-19 Please refer to the NiSource - IBM Outsourcing Announcement of June 21, 2005 ("IBM Agreement"). Please identify how much of the Company's allocated or assigned share of the $21 million in non-cash pension expense will the Company seek to recover from its ratepayers. Please explain how the Company proposes to recover that share of expense.

Response: Please see the Company's response to DTE-18-01 and AG-24-02.

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D. T. E. 05-27

Date: June 30, 2005

Responsible: Stephen H. Bryant, President

AG-24-20 Please refer to the NiSource - IBM Outsourcing Announcement of June 21, 2005 ("IBM Agreement"). Please identify the "technology advances and enhanced service capabilities" that NiSource expects the IBM Agreement to produce.

Response: Please see the Company's response to DTE-18-01 and AG-24-02.

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D. T. E. 05-27

Date: June 30, 2005

Responsible: Stephen H. Bryant, President

AG-24-21 Please refer to the NiSource - IBM Outsourcing Announcement of June 21, 2005 ("IBM Agreement"). Please identify the "growth opportunities "referenced on page 2 of the IBM Agreement to which NiSource intends tore-deploy its capital.

Response: Please see the Company's response to DTE-18-01 and AG-24-02.

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D. T. E. 05-27

Date: June 30, 2005

Responsible: Stephen H. Bryant, President

AG-24-22 Please refer to the NiSource - IBM Outsourcing Announcement of June 21, 2005 (“IBM Agreement”). Please identify which of the 445 NiSource positions slotted for elimination are Company employees.

Response: Please see the Company’s response to DTE-18-01 and AG-24-02.

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RESPONSE OF BAY STATE GAS COMPANY TO THE
TWENTY-SEVENTH SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL
D. T. E. 05-27

Date: June 30, 2005

Responsible: Stephen H. Bryant, President

AG-27-1 Please provide the workpapers, calculations, formulas, assumptions and supporting documentation that were used to determine the $1.6 billion in service fees and project costs flowing to IBM as indicated in the NiSource June 21, 2005 press release entitled “NiSource and IBM sign agreement to transform key business process and technology functions.” Please also breakdown those costs by year for each year of the ten-year agreement for each NiSource subsidiary.

Response: Please see the Company’s response to DTE-18-01 and AG-24-02.

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RESPONSE OF BAY STATE GAS COMPANY TO THE
TWENTY-SEVENTH SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL
D. T. E. 05-27

Date: June 30, 2005

Responsible: Stephen H. Bryant, President

AG-27-2 Please provide the workpapers, calculations, formulas, assumptions and supporting documentation that were used to determine the $530 million in operating and capital cost savings as indicated in the NiSource June 21, 2005 press release entitled "NiSource and IBM sign agreement to transform key business process and technology functions." Please also breakdown those operating and capital costs by year for each year of the ten-year agreement for each NiSource subsidiary.

Response: Please see the Company's response to DTE-18-01 and AG-24-02.

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RESPONSE OF BAY STATE GAS COMPANY TO THE
TWENTY-SEVENTH SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL
D. T. E. 05-27

Date: June 30, 2005

Responsible: Stephen H. Bryant, President

AG-27-3 Please provide the workpapers, calculations, formulas, assumptions and supporting documentation that were used to determine the $35 million in one-time severance costs as indicated in the NiSource June 21, 2005 press release entitled "NiSource and IBM sign agreement to transform key business process and technology functions." Please also breakdown those costs by year for each year of the ten-year agreement for each NiSource subsidiary.

Response: Please see the Company's response to DTE-18-01 and AG-24-02.

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RESPONSE OF BAY STATE GAS COMPANY TO THE
TWENTY-SEVENTH SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL
D. T. E. 05-27

Date: June 30, 2005

Responsible: Stephen H. Bryant, President

AG-27-4 Please provide the workpapers, calculations, formulas, assumptions and supporting documentation that were used to determine the $35 million in transition costs as indicated in the NiSource June 21, 2005 press release entitled "NiSource and IBM sign agreement to transform key business process and technology functions." Please also breakdown those costs by year for each year of the ten-year agreement for each NiSource subsidiary.

Response: Please see the Company's response to DTE-18-01 and AG-24-02.

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TWENTY-SEVENTH SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL
D. T. E. 05-27

Date: June 30, 2005

Responsible: Stephen H. Bryant, President

AG-27-5 Please provide the workpapers, calculations, formulas, assumptions and supporting documentation that were used to determine the $50 million in governance costs as indicated in the NiSource June 21, 2005 press release entitled "NiSource and IBM sign agreement to transform key business process and technology functions." Please also breakdown those costs by year for each year of the ten-year agreement for each NiSource subsidiary.

Response: Please see the Company's response to DTE-18-01 and AG-24-02.

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D. T. E. 05-27

Date: June 30, 2005

Responsible: Stephen H. Bryant, President

AG-27-6 Please provide the workpapers, calculations, formulas, assumptions and supporting documentation that were used to determine the $21 million in onetime, non-cash pension expense related to severed employees and employees who accept positions with IBM as indicated in the NiSource June 21, 2005 press release entitled “NiSource and IBM sign agreement to transform key business process and technology functions.” Please also breakdown those costs by year for each year of the ten-year agreement for each NiSource subsidiary.

Response: Please see the Company’s response to DTE-18-01 and AG-24-02.

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Date: June 30, 2005

Responsible: John E. Skirtich, Consultant (Revenue Requirements)

AG-27-8 Please breakdown the number of employees in the Service Company by function. Please also indicate the number of employees whose responsibilities are:
(1) accounting;
(2) finance;
(3) financial analysis;
(4) information technology;
(5) regulatory matters;
(6) legal;
(7) main and service maintenance;
(8) engineering;
(9) distribution and/or transmission system planning;
(10) sales forecast;
(11) payroll; and
(12) employee benefits.

Response: The Company's does not track employees according to the functions listed above. Please refer to Table AG-27-8 below for a count of service company employees by functional area. The data reflect the Company's organization as of December 2004.

Table AG-27-8

Administration	106
Commercial & Indsty Rel Mkting	28
Communications	18
Customer Service	40
Engineering Services	6
Environmental Safety	77
Finance and Accounting	275
Gas Supply	77
Human Resources	75
Information Systems	535
Internal Audit	21
Legal	34
Operations	47
Planning	3
Purchasing	55
Regulatory	35
Specialty	8
Total	1440